Horizontal Drilling Comes of Age

The upswing in horizontal drilling has pushed the limits of the technique beyond what could be done a few years ago, and what could be dreamed just a decade ago. Increased efficiency, speed and control is enabling drillers to place horizontal wells for optimum reservoir drainage.

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Horizontal drilling has fired the imagination of the oil industry like no other recent technological innovation. From a scattering of early horizontal drilling attempts—in the Soviet Union in the 1950s, China in the 1960s, Canada in the late 1970s and Italy in the early 80s—the technology has moved from fringe to mainstream. Today, horizontal drilling is of unquestioned value and, appropriately applied, affords a range of benefits: increased rate of return from the reservoir, increased recoverable reserves, lower production costs and reduced number of platforms and wells per field. These benefits can be obtained from new wells or by reentering existing wells and completing them horizontally.

Horizontal wells have a higher rate of return than conventional wells because the drainhole is exposed to a significantly larger reservoir area. The greater production of horizontal wells lowers their hydrocarbon recovery cost. In addition, horizontal wells increase recoverable reserves and reduce the number of wells required to sweep a field.

About one-half of horizontal wells are in formations where fractures provide most of the permeability. Because most fractures are near vertical, a horizontal well can intersect far more of them than a conventional well. About 20 percent of horizontal wells are in thin-bed reservoirs (half of horizontal wells are targeted at pay zones of thickness less than 80 feet [25 meters]). The bulk of the remainder is in marginal fields and tight carbonates. In all cases, an additional motivation for drilling horizontally is to reduce water and gas coning (next page). Horizontal wells offer this benefit because they induce lower drawdown pressure than conventional wells.

Incentives for drilling horizontally vary with the hydrocarbon province. In Europe (the North Sea and Adriatic Sea) and the Middle East, the main reasons are low permeability or a permeability anisotropy that favors horizontal drainage. A second reason is avoidance of water or gas coning. In the Far East, horizontal wells are drilled mainly to tap thin oil columns that have a gas cap or a strong waterdrive, and sometimes both. In California and Alaska, the main reason is to avoid gas coning; in the Rockies, horizontal wells improve recovery in thin beds; and in the Midwest and Texas, they maximize intersection with fractures.

It is estimated that by the turn of the century about 50 percent of wells in the USA, and 10 to 50 percent of wells in other countries, will be drilled horizontally—a wide range, owing to the newness of the technology. In the shorter term, horizontal drilling is expected to increase worldwide from about 300 wells in 1990 to up to 2500 in 1995.

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Reservoir characteristics (by percent of wells) for horizontal wells drilled and planned worldwide from 1978 to 1989. Horizontal wells are predominantly used in three settings: reservoirs with fractures, with potential coning problems and with thin pay zones.
Types of Horizontal Wells

The three main types of horizontal wells (below) are defined by the rate at which the radius of curvature is built: short, medium, and long.[1] (see “Comparison of Horizontal Well Radii,” page 25). Short-radius wells are drilled at 1½ to 3 degrees/foot [30 centimeters (cm)]; medium radius is 8 to 50 degrees/100 feet [30 meters] and long radius is 2 to 6 degrees/100 feet. Another well type, ultrashort radius, requires very small borehole diameter and custom-made drilling tools. The small diameter and severe bend of these holes limit services that can be performed in the horizontal section. Ultrashort radius holes are used mainly for recompletion of old producers and can be thought of as an alternative to fracturing.

Medium-radius drilling is used most often on land. The technique was developed in the USA, driven by requirements to obtain the maximum horizontal length allowable within lease lines. Tools used for medium-radius drilling are usually slightly modified versions of conventional long radius equipment designed to endure increased bending and buckling loads. Compared with long-radius wells, medium-radius wells have higher precision of “landing”—the true vertical depth (TVD) at which the well becomes horizontal can be controlled more closely.

Long-radius holes were originally used on land, but now are almost exclusively offshore. These holes employ conventional drilling tools and often use steerable downhole motors (see “Horizontal Drilling Equipment,” page 26).

Today, there is a tendency in medium-radius wells to build some of the well with long-radius sections [next page]. Drillers have found that reducing the build angle at the top of the well allows the hole to be drilled with less torque loss (the difference in torque applied at the surface and measured downhole) than a pure medium-radius well without reducing precision of landing. For example, the first “kickoff” (deviation from the well path) will be 1½ to 2 degrees, rather than 10 degrees, and the second will be 10 degrees.

Steering the Drill Bit

Two methods are used to rotate the bit: surface drives and downhole motors. In the past, surface drive was always performed with a rotary table. But recently, it has been largely replaced by top drive offshore. The top drive system is more powerful, accommodates 90-foot stands (three drillpipes) instead of 30-foot stands and allows rotation and pumping while pulling out of the hole. In the topdrive system, power is generated by a motor in the traveling block instead of at the table. The downhole source of power used in horizontal drilling is usually the positive displacement motor (PDM), powered by mud flow (page 26).

A typical surface rotated bottomhole assembly (BHA) is made of stabilizers, drill collars and measurement-while-drilling (MWD) equipment. The placement and size of stabilizers control inclination (deviation angle from the vertical). Assemblies can be designed to build angle, hold it steady or drop angle. With the use of a downhole adjustable stabilizer, a single

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Comparison of Horizontal Well Radii

Short radius
Advantages
- More precise vertical placement of horizontal drain than medium- and long-radius wells
- Attractive on smaller leases
- Drilled from an existing well so less expensive for recompletion, since most well infrastructure (well, casing, pipeline, roads) is in place
- Because kickoff is usually below fluid contacts, less risk than medium- and long-radius wells with poor isolation between fluid zones.

Disadvantages
- Needs customized drilling equipment that is often slower to handle, less rugged than standard equipment and may not meet API guidelines
- Requires special articulated motor and bottomhole assembly
- No control over borehole azimuth (compass reading with respect to magnetic North) because no MWD tools can fit; azimuth is typically within 20 degrees
- Short horizontal drainhole, often less than 300 feet (90 meters)
- Only openhole completion
- No coring or logging services.

Medium radius
Advantages
- Less torque and drag than in short-radius wells
- Accommodates normal-size MWD tools and the SLIM11 MWD system, which has a 13/4-inch diameter to fit in 31/4-inch drill collars
- Can use downhole motor and steerable system
- Can drill a longer horizontal drainhole—average of 3000 feet (900 meters)—than a short-radius well
- Conventional coring possible
- Can be normally cased and completed.

Disadvantages
- Because of higher build rate than long-radius well, may involve more torque loss and drag and greater stress on drilling equipment
- Limited completion and workover options (if 61/4-inch diameter or less)
- Limited Logging While Drilling (LWD) and wireline logging options (if 61/2-inch diameter or less).

Long radius
Advantages
- Easiest to drill, using conventional drilling equipment and standard tubulars and casing; cost/day of services often lower than in medium- and short-radius wells
- Permits drilling the longest horizontal section—more than 5000 feet (1500 meters), with an average of 3500 feet (1070 meters)—because lower dogleg angle results in less torque loss and drag
- Accommodates all completion, stimulation, workover and gas lift equipment
- Accommodates full suite of logging services.

Disadvantages
- Often requires a top drive system, larger pumps and greater mud/cuttings management capacity
- Its longer openhole section increases risk for pipe sticking, kicks and borehole damage
- Less precise control of true vertical depth placement because the wellbore starts farther from the target. This is becoming less significant with the improved ability of MWD measurements to give real-time correlation of marker beds with offset wells.

4. For a review of horizontal drilling methods:

For an overview and history of horizontal drilling:

Horizontal Drilling Equipment

**Bent housings**
These provide a permanent bend in the BHA of typically 1/2 to 1 1/2 degrees. They are used to build well deviation and control the horizontal trajectory.

**Bits**
Standard tricone bits and polycrystalline diamond compact (PDC) bits are used in horizontal wells. PDC bits can be advantageous in horizontal wells because they last several times longer, making them economic in shaly formations. Their brittleness, however, makes them less suitable for harder, sandy formations. PDC bits are also attractive in horizontal wells because they lack moving parts, eliminating the risk of fishing for lost cones. Because PDC bits tend to generate high reactive torque at the downhole motor, they are prone to departing from the planned toolface setting sooner than a tricone bit. Roller-cone bits have a greater tendency to walk, usually to the right, the direction of drillstring rotation. PDC bits with short-gauge length at low rotary speeds tend to drill straight or walk to the right. Long-gauge PDC bits at high rotary speeds, however, have been found to walk to the left. The reasons for these tendencies are not well understood.

**Downhole adjustable stabilizer**
This is usually used in the straight (tangent) sections of a deviated well as a cost-effective alternative to a standard rotary system. It enables the directional driller to change the build/drop tendency of a BHA without making a round-trip to change the BHA design. The stabilizer gauge is changed downhole by varying the weight on bit, and is locked in place by controlling the flow rate.

**Jars**
These mechanical devices are commonly included in BHAs for freeing a stuck assembly. When a preset tension is reached, the jar trips automatically, releasing a hammer-like mechanism. The impact may bang the stuck assembly loose. Jars can be set to propel the string up or down.

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**Simplified mechanics of a positive displacement motor (PDM) used for drilling in sliding mode. The motor consists of an eccentric rotor turning in a rubber stator. The rotor turns as the mud is pumped through the channel between the rotor and stator.**

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**MWD/LWD**
MWD capabilities include mud pulse telemetry, navigation and drilling mechanics data, downhole temperature, gamma ray and formation resistivity. State-of-the-art navigation uses two triaxial systems, accelerometers to determine inclination, and magnetometers for determining azimuth. MWD measurements are used for directional drilling, geologic correlation, pore pressure prediction, and drilling mechanics interpretation to aid drilling decisions and enhance safety.

LWD data are used mainly for real-time formation correlation² and pore pressure prediction² with more detailed formation evaluation. The Compensated Dual Resistivity (CDR) and Compensated Density Neutron (CDN) tools provide measurements of deep and shallow resistivity, photoelectric factor (Pe), gamma ray, bulk density and a density-based caliper calculation (see “Acquiring and Interpreting Logs in Horizontal Wells,” page 34).

A mud-driven alternator powers both MWD and LWD tools and provides data transmission to the surface via mud pulses. The LWD equipment is capable of collecting more information than can be transmitted to the surface in real time, so some data are stored in downhole memory for reading when the tool is removed from the well. This permits improved log resolution and quality.

**Neutral point**
If the bit is held off the well bottom during drilling, the weight of the drillstring is supported at the surface by the traveling block (neglecting the effects of friction and buoyancy). The entire drillstring is under tension, which decreases from a maximum value at the surface to zero at the bit. Some of the weight is transferred to the bit when it is on the bottom of the well. This places the lower section of the drillstring under compression and the rest of the string in tension. The neutral point is where the drillstring passes from compression to tension.

**Positive displacement motors**
A positive displacement motor (PDM) is located immediately above the bit in a BHA (above, left). It is powered by mud displacing a helical shaft that rotates inside a rubber housing and turns the bit up to several hundred revolutions per minute. (Typical surface drives turn the entire drillstring 150 to 200 rpm).

**SLIM1 MWD tool**
This new MWD system makes real-time measurements of borehole inclination, azimuth, toolface orientation and downhole temperature. The system can be conveyed by slickline, without pulling the drillstring out of the hole.

**Stabilizers**
Stabilizers are used in BHAs to control borehole trajectory and prevent the BHA above the bit from touching the borehole wall, reducing the risk of getting stuck.

**Top drive system**
A top-drive system turns the drillpipe directly, rather than using a rotary table. One advantage is that 90-foot stands of pipe can be used, saving significant rig time handling connections. Also, while the drillstring is pulled from the hole, it can be rotated and circulation maintained, making top drive attractive for horizontal drilling. Pulling the drillstring out of horizontal holes can be difficult when material sloughs off the walls and is not removed completely by circulating mud.

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* Mark of Schlumberger

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Oilfield Review
BHA can serve for building and holding, or dropping and holding. This is a cost-effective solution for maintaining inclination in straight but deviated portions of the wellbore, called tangents.

Rotary assemblies do not permit close control of wellbore azimuth (compass bearing of the wellbore with respect to magnetic North). This control is usually achieved with a downhole motor with a bent housing. When only the downhole motor is on, the bit and the moving part of the motor turn, not the drillstring. This is called sliding mode because the rest of the drillstring slides down the hole after the bit.

In sliding mode, the hole follows the direction of the bent housing on the motor, the direction in which the bit is pointing. A toolface orientation measurement in the MWD equipment tells, in real time, the bit orientation and allows its control from the surface. A typical toolface reading tells bit orientation in degrees to the left or right of the “high side,” the top of the hole. Minor adjustments in toolface are made by changing the downhole weight on bit, which changes the reactive torque of the motor and hence the orientation of the toolface. Large changes are made by lifting off bottom and reorienting the complete drillstring.

Today, the horizontal section is usually drilled with a combination of rotary and sliding modes. Whenever the surface drive is on, the steerable BHA behaves like a normal rotary BHA and maintains inclination and azimuth. Only when the bit goes off course does the driller return to sliding mode to correct the path (left). The directional driller’s goal is to drill as much as possible in rotary mode, which is much faster than sliding mode, and results in smaller doglegs (sharp bends in the wellbore) and hence less drag—the sliding friction exerted by the formation.

Planning a Horizontal Well

Horizontal well planning begins after a thorough review of offset well data has determined the suitability of the reservoir for horizontal development. This review includes data from seismic, wireline, core and cuttings analysis and testing.

Although the literature reports many horizontal drilling successes, prudent engineers also focus on identifying and learning from mistakes. The typical failure results from insufficient planning. Knowledge of stratigraphy is usually thorough, but information may be missing on structure and petrophysics—Where are the faults? What is the predominant fracture orientation? What are the reservoir’s horizontal heterogeneities? Without identifying what is known and unknown, preparations cannot be made for each contingency. Questions that arise during drilling, such as determining whether the bit exited the top or bottom of the pay zone, may be difficult to answer if the well is drilled in a way that prohibits logging. Ample evidence suggests that careful planning before spudding a horizontal well can mean significant savings and improved drilling efficiency and can facilitate setting of casing and completion.

Planning includes several steps (not necessarily in this order):

- Offset well data review. Because most horizontal drilling is for development of established fields, offset well data are usually available. The first step in planning a horizontal well is to evaluate well logs, drilling reports, mud logs, geologic maps and cross sections. Horizontal wells can be drilled more efficiently by knowing which drilling practices worked and which didn’t in the offset wells, how different formations responded to mud systems, how various BHA’s worked and actions taken by the driller and their consequences. Review of offset and directional drilling data can take a couple of days to a week.

- Well profile selection. The well profile, the path that the well takes, is dictated by reservoir geometry, well platform location, maximum build rate, reservoir structure (dip angle and direction) and pay zone fluid distribution. These tell whether pilot holes are necessary, determine rig location for onshore wells, kickoff points, build radius, the angle of turn (changes in borehole azimuth with respect to magnetic North) required by the profile, the number and angle of tangents, length of the horizontal section and tolerance in reaching the target and in maintaining the planned profile. The well plan accounts for readily distinguished geologic markers detected on the way to the target. It must also allow for revision, increase in case of change in target entry true vertical depth, in kickoff points, build rate and tangent section length and angle.

- Torque and drag analysis. Torque loss—the difference between uphole and downhole torque—and drag are fundamental drilling efficiency measurements. Planning programs help optimize the well profile and minimize friction by predicting surface torque and hook loads (including drag) while drilling and tripping for given fric-

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tion factors (the ratio of sliding force to side force on the wellbore wall [below]). The procedure has two steps. The first is to determine from offset, deviated wells the coefficients of the two types of drilling friction: rotating friction (which affects torque) and sliding friction (which affects hook load). These coefficients, which depend on local lithology and mud design, are calculated from surface torque, hook load, drillstring design, casing programs and hole conditions.

The second step is to use the friction factors and planned BHA, casing and mud system to predict the hook load and torque for different well profiles. The ideal minimum drag profile is given by a well that changes from vertical to horizontal with a single, continuous bend, without tangent sections. Such a well would require a prohibitive number of BHA changes. The ideal profile is then adjusted with realistic build rates and tangent sections to minimize BHA changes, and to locate geologic marker beds in the tangent section above the final build section. The presence of a tangent section gives the directional driller the opportunity to change the location of the final build section if marker beds are not found where they were expected. This enables the planner to find a realistic profile that minimizes torque and drag.

Further reduction in torque and drag might be made by considering different BHA designs. The result, a theoretical output of torque and drag, is used to specify rig power and drilling equipment. This specification may be fine-tuned by simulating the torque and drag expected for doglegs of various severity.

- BHA response prediction (for both rotary drive and downhole motor assemblies). This optimizes BHA design by accounting for drillpipe type, number and placement of heavywall and conventional drill collars, motor design, and stabilizer shape, size and placement.

The ideal steerable BHA design maximizes the time spent drilling in surface rotary mode as opposed to sliding mode and minimizes corrections made by drilling in sliding mode (next page, top). Rotary mode is more desirable because it permits a higher transfer of torque from the bit. This gives penetration rates many times greater than in sliding mode because rotation of the entire drillstring significantly reduces axial drag. In sliding mode, drag can limit total horizontal displacement.

It is often not obvious which steerable BHA design maximizes rotary drilling. In the absence of local field data, the BHA behavior can be modeled in rotary and sliding modes. However, computer modeling cannot predict real-time hole enlargement and rock strength anisotropy. These can have first order effects on BHA directional performance and are largely unknown during drilling. As experience grows in a given area, the appropriate BHA can best be identified from experience by using computerized data bases containing local drilling parameters and information describing BHA sizes and tendency to build, drop and walk.*

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* Predicted hook load (load at the surface) expected for a drillstring at total depth (TD) for the trajectory shown on page 25 using offset well friction factors. Note changes in the loads at the two kickoff points. Pick up load is determined when the drillstring is lifted off bottom; rotating string weight is weight when rotating off bottom. Slack off weight corresponds to running in the hole. Hook load increases to the second kickoff because load on the hook is increasing as the traveling block supports more stands of pipe, but rotating string and slack off weights drop after the second kickoff because an increasing amount of pipe is resting in the horizontal borehole, not being supported by the hook. Pickup overpull tells how much upward force, in excess of the drillstring weight, the driller needs to pull the drillstring off bottom; knowing this value is essential because it must not exceed the rating of the rig. Slack off drag is how much weight the driller needs to release to let the drillstring slide downhole.
A cost-effective solution to increase the versatility of the BHA is to use a downhole adjustable stabilizer (right). Placed in a standard rotary BHA or above the steerable system, it allows the driller to modify the build or drop tendency of the BHA. This minimizes time-consuming well path corrections, in which the driller must stop drilling in rotary mode, reorient the bit, drill in sliding mode until the well path reaches the desired inclination, then continue drilling in rotary mode. The time lost from drilling in the slower sliding mode can be significant.

- Determination of MWD requirements. The foremost requirement is reliability. Low mean time between failure (MTBF) is important in horizontal wells because of the cost of long trips to change the tool if it fails and the danger of leaving the hole exposed to the mud too long. In today’s competitive environment, a typical MTBF exceeds 250 operating/pumping hours.

The next consideration is usually cost-benefit analysis. For example, in a straightforward, onshore horizontal well in a known formation, a service comprising only deviation and inclination (D&I) from a slickline-retrievable MWD tool may be appropriate. If the drillstring becomes stuck, the tool can be pulled out the hole by slickline, avoiding high “lost-in-hole” charges. For wells offshore, in a complex or poorly understood area, D&I plus MWD geologic correlation and downhole drilling mechanics measurements might be more appropriate to conserve rig time. These can be upgraded with LWD density and neutron measurements, particularly when running wireline logs in the horizontal section is difficult.

Another MWD consideration is the speed of data update during critical course corrections. The rate at which toolface orientation data are updated, for example, varies from every 3.6 seconds to nearly every minute. The fast rate becomes critical for accurate steering when using polycrystalline diamond compact bits, which generate more reactive torque at the motor. This torque makes the bit prone to diverging from the planned toolface setting sooner than a conventional bit.

Accuracy of MWD azimuth and inclination becomes especially important in...
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| Range                                           |                    |
| Temperature                                     | 32°-302°F (0°-150°C) | ±1°F (±0.5°C)   |
| Drift                                           | 0°-180°            | ±0.1°          |
| Azimuth                                         | 0°-360°            | ±1.3° @ 5° inclination, ±0.9° @ 10° inclination, ±0.6° @ 20° inclination |
| Toolface orientation                            | ±0.1°              | 1.5°            |

| Specifications of Anadrill’s MWD1 and new SLIM1 MWD systems. The MWD1 system is conveyed on conventional drillpipe; the SLIM1 downhole tool is 1 3/4 inches in diameter and can be run in standard nonmagnetic drill collars with OD of 4 1/4 to 9 5/8 inches. |

horizontal wells (above). Small discrepancies throughout build and tangent sections can sum to large discrepancies at target entry. For example, in a well starting its first build at 3 degrees/100 feet, entering a 200-foot (60-meter) tangent at 45-degree inclination, and a second build at 10 degrees/100 feet, a discrepancy of 0.2 degrees translates into a 14-foot (4-meter) discrepancy in TVD. This could be critical in some formations, such as the Bakken shale in the Rockies, where a typical target thickness is about 7 feet (2 meters).

- Selection of customized horizontal tools. These include the downhole adjustable stabilizer and specially designed stabilizers that avoid excessive drag and hanging, double-bend motors and motors with custom stabilizer blade or skid pads to perform at a specific build tendency, nonmagnetic heavy-weight drillpipe to avoid dragging and higher (compressive) strength drillpipe.

- Placement and setting of jar(s) (see “Horizontal Drilling Equipment,” page 26). Experience has shown that in horizontal holes, two jars can be used, one in the vertical section and the second in the horizontal section that strikes up only. The two-jar arrangement is used because the vertical jar may not have enough power to free a stuck BHA.

- Determination of casing design. Torque and drag analysis helps determine if casing can be run in hole and if it can be reciprocated and rotated during cementing.

- Hydraulic computation. In horizontal wells, cuttings tend to form a bed on the low side of the borehole (see “Drilling Fluids for Horizontal Wells,” page 8). This can be removed by ensuring the mud is in turbulent flow in the annulus and by keeping the pipe moving. Modeling the hydraulics of the mud/BHA system can help select drilling equipment and mud pumping rates to optimize bit and annulus cleaning and cuttings transport.

- Evaluation of horizontal borehole stability. Boreholes can fail by fracturing or sloughing. Fracturing occurs when the rock’s tensile strength is exceeded. Sloughing, the more common mode, occurs when the rock’s shear strength is exceeded. Because stresses imposed by drilling fluids are different from intrinsic stresses in the rock, and because chemical changes can occur from mud/formation interactions, deformation or failure of the borehole wall can occur during drilling.

Mechanical borehole stability can be estimated with rock failure models, which predict the maximum and minimum mud weights between which drilling can safely proceed without inducing tensile failure of the well from excess mud weight, or sloughing from insufficient mud weight (next page and page 8). The method identifies in-situ stresses in the formation from offset wireline logs, calculates stresses that will occur at the borehole wall when the well is drilled directionally, and substitutes these borehole wall stresses into shear and tensile failure criteria to see if failure will occur.

In Anadrill, all of these planning steps are coordinated by the Drilling Planning Center (DPC) manager at the onshore computing center in communication with the client at the base office. At the field support level, Schlumberger activities in horizontal wells are coordinated by the Horizontal Integration Team (HIT). The group addresses client needs in horizontal wells by collecting, analyzing and dispatching information from worldwide sources.

**Monitoring & Controlling Horizontal Drilling**

Progress during drilling is continuously compared with the well plan. As new data become available during drilling, modifications in the well plan are made where appropriate. Contingency plans are then enacted when changes from the optimum plan arise, such as a BHA that does not perform as expected, or unmapped faults or unconformities are encountered. Monitoring and control are made using three families of measurements: MWD directional data, MWD drilling mechanics data and LWD data. Processing and analysis of these data are performed at the surface using a data acquisition and interpretation system.

MWD directional data—inclination, azimuth and toolface orientation—are used to monitor drilling and check that it follows the well plan. A problem in predicting steerable system behavior is that inclination data come from at least 60 feet (18 meters) behind the bit. By the time the driller obtains inclination data and takes corrective action, the bit may have veered off target. The Downhole Torque (DTOR) measurement, because it is made at the bit, helps improve directional control in sliding mode. Keeping DTOR constant helps maintain constant toolface orientation.
Mechanical Stability (MSL) Logs for wells deviated 0° and 50°. The Fracture Initiation Pressure, or pressure at which tensile failure would occur, is plotted in the left and bottom tracks. In the center tracks, the area between the limits for shear failure is shaded black. In the right and top tracks, the Fracture Initiation Pressure and limits for shear failure are combined to indicate the recommended range of mud weights.

In this example, the Fracture Initiation Pressure is greater than the maximum pressure for shear failure, so the shear failure and max/min tracks are identical. The lower boundary of the shear curve is always the same as the lower boundary on the max/min curve. The upper boundary of the max/min curve is the upper boundary of either the shear failure or fracture initiation pressure curve, whichever is lower. The range of recommended mud weights decreases significantly for the 50° case—in general, the possible range of mud weights decreases with increasing deviation. Comparing the shear failure and max/min tracks in the vertical well at 2672 meters shows that sloughing would be the expected mode of failure. Because the zone is relatively thin, it probably would not create significant drilling problems.

If the zone at about 3520 meters in the 50° well were thicker or the anticipated failure were caused by fracturing and loss of circulation, the well trajectory might need to be revised to cross the zone at a lower deviation angle. Differences in recommended mud weights in different zones in the well might also be used to determine casing points. Wellbore failure through chemical reactions of the mud with shale sections is controlled in the same manner as for vertical wells. Experience has shown that MSL results tend to be conservative and are best used to pinpoint zones where problems could occur. (After Bruce, reference 10.)

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The Downhole Weight on Bit (DWOB) measurement allows better control of the steerable assembly when used in rotary mode, because weight applied to the bit affects bending of the assembly and hence its building or dropping tendency. In sliding mode, the DWOB measurement is particularly useful because of the high drag, which invalidates measurements from the surface.

The DTOR measurement can also be used to determine downhole motor efficiency and motor failures (left). Large increases in reactive torque can indicate cone locking.

Monitoring and control of drilling is also enhanced by two real-time interpretation programs, the Mechanical Efficiency Log (MEL) and the Sticking Pipe Indicator (SPI) computations. These calculations make use of drilling mechanics data—DWOB and DTOR measurements, surface weight on bit, surface torque, rotations per minute (RPM), and rate of penetration (ROP).

The MEL computation determines the efficiency with which shaly formations are drilled in real time, evaluates the state of bit wear, detects locked cones, and can also improve PDC bit performance. The SPIN program computes sliding friction (drag) and rotating friction acting on the drillstring.

Use of MEL and SPIN computations to evaluate weight transfer to the bit. In sliding mode (color bands), ROP (rate of penetration) declines because of inhibited weight transmission to the bit. In a neighboring well, the driller used a surface weight on bit of 65,000 lb to achieve an ROP of 2 feet (60 cm)/hr. Because the driller had no measurement of downhole weight on bit, this weight was considered optimal. Anadrich analysis showed that, in this well, by increasing the SWOB to 85,000 lb (off scale in SWOB) and downhole weight on bit to 15,000 to 25,000 lb, ROP increased to about 10 feet (3 meters)/hr.

In the lower track, Friction is rotating friction factor; Drag is sliding friction factor. While in sliding mode, STOR goes to 0, because no rotation is applied to the drillstring. But the DTOR measurement does not drop to 0 because of reactive torque—about 500 feet/lb—of the downhole motor against the drillstring, which is not seen at the surface because it is usually lost in friction with the wellbore. This reactive torque indicates that the motor is working.
while on bottom.\textsuperscript{13} A separate “trip monitor” computes drag while tripping. The results can be used to recognize incipient drillstring sticking early enough to allow correction—wiper trips, circulating, mud conditioning or reaming. Periods of poor drillstring response can be minimized by differentiating formation changes from drillstring sticking above the MWD sensors. SPIN computations also can be used to quantify the effectiveness of hole conditioning (previous page, right and below right). The friction factors are computed foot by foot while drilling. Because they replace offset well assumptions with real data from a horizontal well, they can enhance post-drilling analysis by fine-tuning torque and drag modeling for future wells.

Marker beds can be identified while drilling to determine the best location for kickoff and casing points. The earliest identification can be made from mechanical properties of the rocks. If a marker bed is harder or softer than surrounding formations, it can be identified from changes in ROP and DTOR measurements. The identification can be confirmed and clearly correlated in offset wells using MWD gamma ray and resistivity measurements.

Post-drilling evaluation with the operator helps guide subsequent drilling in the area. For example, updates are made on wellbore friction, BHA and bit performance and the geologic map. This follow-up and analysis increase local knowledge and shorten the learning curve, resulting in faster, more efficient drilling on the next well. —MF


Use of MEL and SPIN computations to evaluate the effectiveness of a “short trip”—running the drillstring up to the casing shoe to condition the well. Note that before the trip, the driller is trying to keep the DWOB value constant to maintain good penetration rate. After the trip, less SWOB is needed to maintain the same DWOB value, indicating that the trip improved the condition of the well. This is also shown in the top track: drag is reduced after the trip, suggesting that the hole is in better condition, with fewer cuttings. Drag increases with depth but does not exceed the precleaning value. Friction changes are negligible. In the bottom track, excess torque (XSTQ—torque above that expected to drill the formation) was identified as due to the PDC bit becoming undergauge and the first stabilizer cutting into the formation. This was confirmed when the bit was pulled out of the hole and found to be about 1/8 inch undergauge.